NATURAL GAS REPORT TO THE REGULATORY FLEXIBILITY COMMITTEE OF THE INDIANA GENERAL ASSEMBLY

By the Indiana Utility Regulatory Commission
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Natural Gas Industry Overview

Industry Structure

Local gas distribution companies (LDCs) are categorized as either municipally or investor-owned. Despite their different forms of ownership and corporate structures, municipal and investor-owned utilities share the goal of providing reliable gas service at reasonable cost. Both types of utilities serve as resellers and transporters of gas to their retail customers. Typically, gas utilities purchase gas supply and transportation rights rather than having any ownership in production or pipeline facilities, i.e. they are not vertically integrated.[1]

Investor-Owned Utilities

Investor-owned utilities (IOUs) are the largest sellers of natural gas to retail customers in the United States. In Indiana, there are three large IOUs providing gas service, Indiana Gas Company, Inc. (IGC), Northern Indiana Public Service Company (NIPSCO) and Southern Indiana Gas and Electric Company, Inc., (SIGECO), and 17 smaller IOUs. The three largest IOUs are owned by holding companies; NiSource is the parent of NIPSCO and Vectren owns Indiana Gas and SIGECO. Two of these companies, NIPSCO and SIGECO, are combination utilities that provide electric service as well as gas service.

Municipally Owned Utilities

Municipals are organized as not-for-profit local government entities. They pay no taxes or dividends, although revenue can be turned over to the general city fund in lieu of taxes if the city elects to do so, and raise capital through the issuance of tax-free bonds. There are 19 municipally owned gas utilities in Indiana. Only two are regulated by the Indiana Utility Regulatory Commission (IURC or Commission): the state's largest municipal gas utility, Citizens Gas and Coke Utility (Citizens), which serves Indianapolis, and Aurora Municipal Utility.[2]

Indiana Sales and Transportation of Gas

Gas utilities serve as both merchants, providing bundled sales and transportation service to many of their customers and transporters, moving gas through their systems for industrial and commercial customers that have purchased gas directly from producers or marketers.

Table 1 presents sales information for Indiana's four largest LDCs: Citizens, IGC, NIPSCO and SIGECO. Sales figures are based on sales of gas made by LDCs to customers that purchase bundled service, which includes both the provision of gas and its transportation. These four companies

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[1] Vertical integration is a firm's involvement in all stages of the production of goods, from the procurement of raw materials to the sale of finished goods.

[2] In Indiana, municipal utilities may "opt out" of the Commission's jurisdiction in favor of local control over rates.

collectively represent about 90 percent of the natural gas retail deliveries in the state. For more detailed information, see Appendix A.[3]

Table 1: Sales (Dth) for the Four Largest Gas Utilities in Indiana - 2000

Utility	Residential	Commercial	Industrial	Other	Total
Citizens Gas	25,385,884	14,925,141	8,364,368	-	48,675,393
Indiana Gas	46,504,000	18,852,000	8,235,000	-	73,591,000
NIPSCO	66,450,000	22,951,000	13,045,000	24,786,000	127,232,000
SIGECO	8,745,355	3,794,058	553,415	633,180	13,726,008

Source: IURC Company Annual Reports on file with the IURC

The Natural Gas Market

High gas prices for all sectors have caused considerable public concern about the present and future operations of the gas industry and markets.[4] Recent increases in gas prices have given rise to questions related to the role that natural gas will play in achieving economic growth. This is a particularly salient issue for Indiana policy makers because much needed increases in its production of electricity are expected to be gas fired while the demand for gas for heating and industrial purposes continues to grow. Although the role of natural gas will be pivotal in meeting the energy needs of Indiana, the exact nature of that role has yet to be determined.

The Rapid and Drastic Increase in Gas Prices

In 1998, natural gas prices were below $2.00 per MMBtu, which were the lowest prices in real terms in twenty-five years.[5] As a result, industry investment, drilling and proved natural gas reserves declined. Meanwhile, gas demand jumped by 4.8 percent in 2000. This stronger than normal demand for gas was evident in the spring of 2000 when demand normally abates and prices significantly moderate. Instead, gas prices began to rise dramatically in the spring of 2000 and the refill of gas storage slowed as the industry waited for prices to moderate.

Gas storage was aggressively filled in late August and October 2000 because storage injections were minimized over the summer as demand accelerated and prices increased. As a result, gas prices stayed high and gas storage levels were at a five-year low. The winter of 2000-01 began with much colder than normal weather in November and December, which reduced gas stocks to such low levels that it raised concerns about possible supply shortages during peak periods for the rest of the winter. The unusually high demand and rapid gas supply draw-down strained productive capacity and drove up natural gas prices. The average wellhead price of natural gas was 144% higher for the 2000-01 heating season than the average for the prior heating season.

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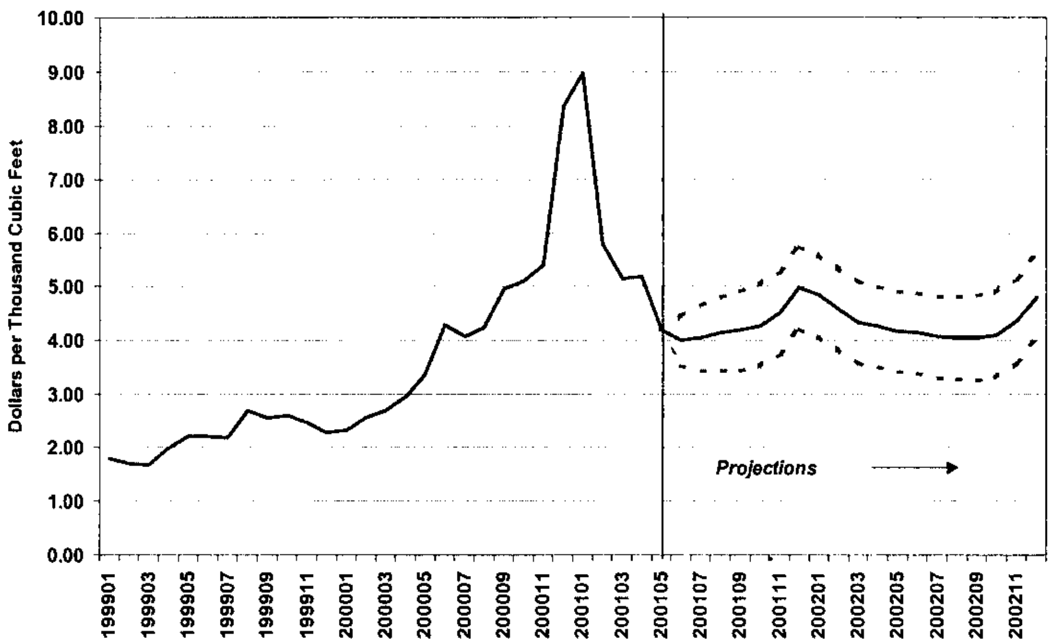
[3] Retail sales are typically categorized by class of customer, i.e., the residential, commercial and industrial customers. The designation "other" refers to sales to public authorities, i.e., governmental entities.

[4] The sectors of the gas market are groupings based on the types of customers receiving gas service and are typically considered to be residential, commercial, industrial and electric generation.

[5] One million Btus of gas is equal to an MMBtu, one thousand cubic feet (Mcf) or a Dth. A Bcf is a billion cubic feet and an MMcf is a million cubic feet.

Table 2: Actual and Projected Gas Prices



Source: Energy Information Administration

The dynamics of the gas market indicate that prices will not be returning any time soon to the low of $2.00 per MMBtu experienced more than a year ago. Recent EIA price updates for gas purchases indicate that prices fell from around $5.00 per MMBtu in April to below $4.00 in June and have been just above $3.00 for July. Lower prices are the result of increased levels of supply relative to demand, which has decreased because of relatively mild weather and electric utilities turning away from natural gas in favor of other fuels. To give effect to these developments and reflect the belief that the possibility of gas prices surging is now considered remote, EIA has reduced its annual projection made in May 2001 for gas prices from $4.85[6] to $4.50 per MMBtu.[7]

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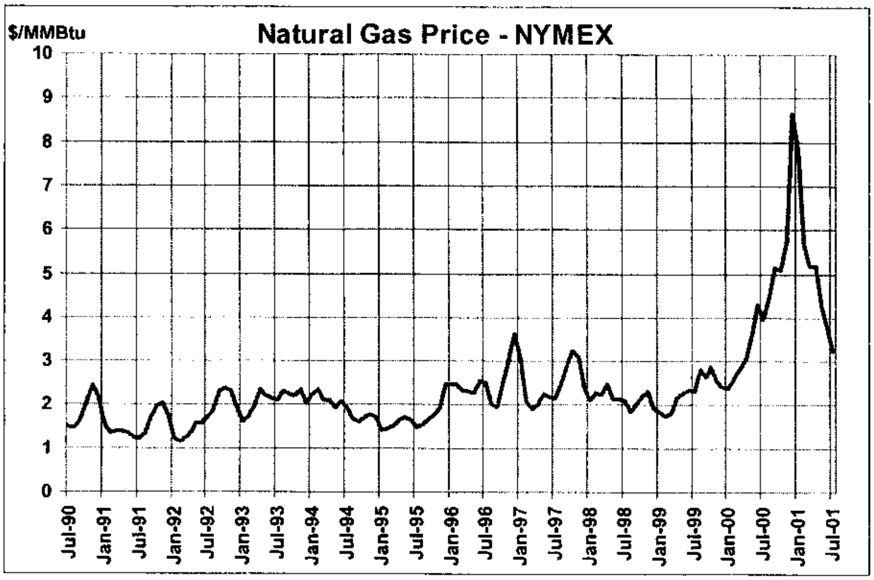
[6] Energy Information Administration, U.S. Natural Gas Markets: Recent Trends and Prospects for the Future SR/OIAF/2001-02, May 2001.

[7] Energy Information Administration, Short Term Energy Outlook – July 2001, July 6, 2001.

Table 3: NYMEX Natural Gas Prices

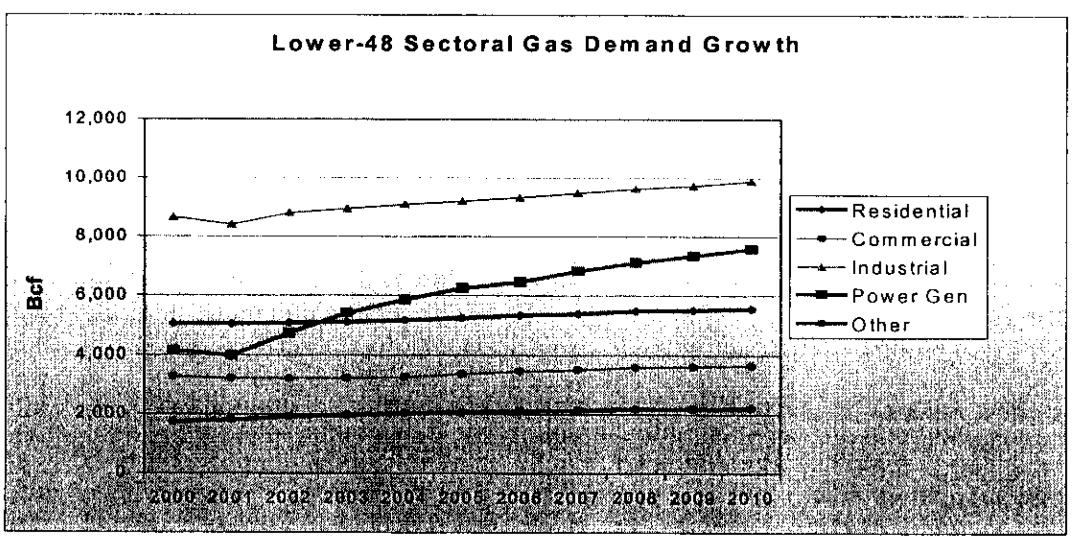


Source: Energy Information Administration

<u>Gas Demand and Supply</u>

One of the factors that contributed heavily to recent increases in the price of natural gas nationally was the new peak in gas consumption established last year. A strong economy and higher heating and cooling loads caused this strong demand throughout 2000. Residential consumption in December 2000 and January 2001 was at record levels. Gas use by electric generators increased from 1999 despite the high prices of natural gas in 2000. The EIA projects that future increases in the demand for natural gas will be primarily due to increased consumption by the industrial and electricity generation sectors, which is depicted in Table 4 below.

Table 4: Projected Demand Growth by Sector



Source: Energy Information Administration

Although production of natural gas rose last year it lagged the increase in consumption. Record levels of gas imports, primarily from Canada, filled the gap between demand and consumption. Much of the pipeline construction over the past several years has been to expand capacity for Canadian gas into the Midwest market, which increased by 58% in the Central region, with most of that destined for the Midwest. Current pipeline capacity levels into the Midwest were sufficient to meet the 2000-01 winter demand even though it was colder than expected. However, additional capacity to the Midwest will be needed because of growing demand. Proposals to build new and expanded natural gas pipelines into the Midwest over the next several years suggest that as much as 2.7 billion cubic feet per day of additional capacity may be needed.

Delivering new gas supply to expanding markets will depend on improved exploration and production technologies, substantial increases in drilling, pipeline investment and drilling crews to meet projected gas production levels. Just as importantly, the contentious and time consuming processes for the siting and permitting of gas industry facilities (storage facilities and pipelines and distribution mains) must be streamlined and expedited to insure timely infrastructure expansion.[8]

Commission Actions Addressing Increased Gas Prices

Gas Forum 2000

On August 30, 2000, the Commission held a one-day gas industry conference and invited several LDCs, as well as representatives of natural gas pipelines and social agencies, to discuss the current and projected natural gas price volatility and supply situation and to report on customer relations preparations, i.e. increasing customer awareness of the situation, planning to deal fairly with non-paying customers, creating or expanding budget billing plans, etc.[9] This forum provided the Commission with valuable information concerning gas storage plans and gas supply arrangements and, more importantly, laid a foundation for much of the work the Commission did in late 2000 and early 2001 in regard to budget billing and customer education.

The Price Spike of 2000-2001

The Commission addressed increased fuel costs for gas utilities in the Gas Cost Adjustment (GCA) proceedings.[10] The GCA is a mechanism whereby gas utilities are permitted to flow through changes in their cost of gas purchased either quarterly or semi-annually in what is usually a routine and summary proceeding.[11] During the winter of 2000-2001, however, these cases took on an unprecedented

[8] *Id.*

[9] Natural Gas Forum industry participants were BP Amoco, American Gas Association, NiSource, Citizens Gas & Coke, Vectren, and Midwest Natural Gas. The Family and Social Services Administration and the IN Community Action Association represented customer perspectives. The Office of the Utility Consumer Couselor also participated.

[10] Indiana Code § 8-1-2-42 and § 8-1-2-42.3 (Indiana SB 637).

[11] The current traditional GCA procedures were established in generic GCA proceedings in 1983 and 1986. By statute, gas utilities may apply for GCA changes not more often than every three months. Several utilities have requested that the Commission allow them to use different time frames for GCA applications—some longer (6 months) and some shorter (monthly) than the standard three-month period. Indiana SB 637 provided IURC authority

significance, as proposed increases to some customers' bills were estimated to be from 30 to over 40 percent higher than the prior quarter. For more detailed information, see Appendix B.

The GCA is a voluntary process that allows LDCs to recover gas costs on a timely basis and to match costs and revenues. The actual GCA rates represent the recovery of the incremental difference in the cost of gas actually purchased from the cost of gas included in a utility's base rates. By allowing utilities to recover or return the costs of gas that are above or below the base cost of gas, the need for frequent, costly rate cases has been diminished.

In periods of low gas prices and low gas price volatility, the GCA remains "below the radar" for most customers. The increased natural gas prices and volatility of 2000 and 2001 brought the GCA into the spotlight. Specifically, the purchasing practices of gas utilities were put under both the public and the regulatory microscope.

During the course of GCA review for the 2000-2001 winter, the Commission took the following actions: 1) issued data requests to obtain a variety of information from gas utilities, 2) aggressively reviewed the gas costs of utilities, 3) approved settlement agreements that provided for voluntary reductions in gas costs and/or increased contributions by utilities to energy assistance funds, 4) reopened existing cases to review the supply agreements of IGC and Citizens with ProLiance, the utility-owned marketer, and 5) approved proposals by utilities that changed the periods over which gas costs were recovered to help alleviate the future financial burden of customers.

Taken together, the orders of the Commission provided relief from high gas prices by managing the billing and cost recovery of gas costs by utilities. The Commission allowed utilities to mitigate the effects of high gas prices on consumers' current and future winter bills by lowering gas costs and transferring significant portions of under recovered gas costs to non-heating months. Finally, the Commission's orders increased the availability of self-help measures and resources to consumers having difficulty paying their bills.

Commission Ordered Data Requests

The Commission issued data requests to produce information explaining the basis for utilities' gas costs. This information was to include a description of utility efforts to obtain gas at the least possible cost and management of the company's gas supply portfolio. These data requests also sought extensive information on conservation programs, customer education efforts and information related to any refunds or rebates that utilities had received or were expected to receive that would be returned to individual customers.

to depart from traditional GCA procedures (i.e. Gas cost incentive mechanisms, Alternative Regulatory Plans, and GCA procedure revisions).

Budget Billing Plans

The Commission also instructed utilities to redesign their budget billing plans for Commission approval. Budget billing plans estimate a gas customer's bill for a year, and levelize the payments over an eleven-month period. Any over or under collections of gas costs are refunded or billed in the twelfth month of the billing year. The parameters of the redesigned Budget plans included that: 1) they be made available to all qualified customers at any time during the year, 2) there be no requirement of a deposit by customers for participation, 3) a plan be offered by utilities to prorate over the first five months of the succeeding budget year without interest any amounts exceeding 50% of the budget billing amount due in the twelfth month, and 4) provisions for the participation by small business and farming operations, schools and not-for-profit institutions be made. Utilities were required to communicate the availability of budget plans to their customers and to advise and educate customers as to the availability of public or other assistance to customers unable to pay their bills.

Aggressive Review of Utility Gas Costs

During the course of GCA approvals for the winter months, the Commission focused its attention on the reasonableness of gas costs for Indiana's utilities. At the conclusion of the Commission's investigation of IGC's gas costs, the Commission approved a disallowance of gas costs of $3.8 million due to a gas planning and procurement process that "...was inadequate to address the extreme volatility and price increases present in the gas supply market."[12] The Commission believed that some increases in gas costs would have been avoided if IGC had followed its past practice of fixing a portion of its prices for gas in advance of the heating season to mitigate price volatility. The Commission went on to state that it did not intend to reconstruct a prudent gas portfolio or to specify the composition of future portfolios because this would reduce the flexibility of the utility for making gas purchasing decisions. It was the responsibility of the utility to be prepared in each GCA to demonstrate that its purchasing strategy was reasonable, and its planning process extensive, rigorous and robust.

Voluntary Settlements and Contributions to Energy Assistance Programs

To resolve the outstanding issues in the IGC and SIGECO cases, the companies, Office of the Utility Consumer Counselor and interveners entered into voluntary agreements that were approved by the Commission on April 30, 2001. IGC agreed to promptly reduce its GCA rates to reflect the $3.8 million reduction in gas costs to immediately lower rates to customers. IGC also agreed to contribute $1 million to LIHEAP (Low Income Home Energy Assistance Program) for the winter of 2000-01 and designated an additional $250,000 to its matching funds for the Share the Warmth Program. SIGECO agreed that it would contribute an additional $700,000 to LIHEAP and provide assistance to qualified gas customers in its service area.

To settle the disagreements in the Citizens case with respect to whether the Company procured gas at the lowest reasonable price during the winter of 2000-01, the parties agreed that Citizens would credit $3.38 million to its customers during the five months commencing November 2001 to provide lower rates during the next heating season. Citizens also agreed to contribute an additional $500,000 to

[12] Indiana Gas Company, Inc., Cause No. 37394-GCA 68. Interim Order approved 1/04/2001. Page 11, Sec. 10.

the Warm Heart Warm Home Foundation for use during the next heating season, and an additional $200,000 to the Indiana Community Action Association for a weatherization program in the Company's service area.

NIPSCO voluntarily contributed $1.3 million to the NIPSCO Supplemental Energy Assistance Fund to assist customers having difficulty paying their bills.

Review of the Supply Agreements of IGC and Citizens with ProLiance

ProLiance Energy (ProLiance) is a limited liability company that is owned jointly by affiliates of IGC and Citizens.[13] ProLiance was designed to provide the following synergistic benefits to the utilities: 1) combined gas supply and planning functions, 2) enhanced leverage in the wholesale gas marketplace and 3) non-duplication of resources previously devoted to these functions. The Commission approved the contractual arrangements between the utilities and ProLiance on September 12, 1997, but established subsequent proceedings to subject them to further scrutiny, which were delayed pending the resolution of appeals of the original order.

At the request of IGC and Citizens, the Commission agreed to proceed with these cases. The Commission noted that the gas sales and portfolio administration agreements between the utilities and ProLiance had expired in October 2000, just as Indiana consumers began to bear the brunt of one of the highest priced heating seasons in years and needed to be revisited. The Commission stated that both utilities should demonstrate that in light of the dramatic increases and fluctuations in gas prices their use of ProLiance during this period as a single source marketer was a prudent gas procurement practice that resulted in the lowest gas costs reasonably possible.

Changes in the Timing of Gas Cost Recovery to Diminish Impact on Winter Bills

Normally, under recovered gas costs are billed to consumers in subsequent periods, with most of the cost recovery occurring over the high use winter months. Because the GCAs approved for billing over the 2000-01 winter were based on understated estimates for gas costs, the under recovered gas costs of many Indiana gas companies were significant. To mitigate the effects of the under recoveries on bills for the next year, IGC, SIGECO and Citizens negotiated with the OUCC, and the Commission approved, the movement of significant portions of the under recoveries from the normal winter 2000-01 recovery period to the non-heating months preceding and following it.

Commission Actions in Anticipation of Winter 2001-2002

In an effort to gauge where LDCs stand in relation to a year ago and to allow them to report on their successes and failures over the past year-and-a-half, the Commission sponsored a second Gas Industry Forum on July 27, 2001. This forum focused exclusively on Indiana gas companies and their preparations for the upcoming winter heating season. Vectren (IGC and SIGECO)[14], NIPSCO, Citizens,

[13] IGC Energy, Inc., a sister company of IGC, and Citizens By-Products Coal Co., a wholly owned subsidiary of Citizens, each own 50% of ProLiance and, through a board, maintains 50% control over it.
[14] On April 1, 2001, SIGECO and IGC began operating under the name of Vectren Energy Delivery of Indiana. The name change was approved by the Commission and reflects the merger of the companies.

Ohio Valley Gas and Indiana Natural Gas made presentations. In preparation for this gas forum, the Commission once again issued another round of questions to all LDCs, which emphasized the effects of last winter's high gas prices on the individual companies and their customers.

Other Gas Issues Affecting Indiana

Monthly GCA Filings

The majority (19 out of 22) of Indiana's LDCs file traditional quarterly GCA petitions. One of these, IGC, has elected to continue to file quarterly, but is allowed to "flex," or adjust, its GCA factors down from Commission approved maximum factors, or caps, once a month in an effort to more closely reflect current gas prices. Because IGC and SIGECO are now wholly owned subsidiaries of Vectren, SIGECO, in its most recent GCA, filed for monthly GCA factors to consistently charge all Vectren customers using a monthly GCA mechanism.[15] The Commission did not allow the "flex" option at this time and reserved the issue of "flexing" SIGECO's GCA factors to be dealt with in future proceedings. However, SIGECO was allowed to implement preapproved monthly factors for the months of Aug., Sept., and Oct. 2001.

Currently, one LDC, NIPSCO, implements a monthly GCA factor with an annual hearing to discuss important issues pertaining to the previous and upcoming years, to true-up any under- or over-estimated costs, and to present known demand costs for the upcoming year. NIPSCO's GCA mechanism, approved in an Alternative Regulatory Plan (ARP), allows monthly flexing up or down based on prevailing market conditions.[16] In addition to the annual hearing requirements, NIPSCO is required to file monthly informational filings with the Commission showing commodity prices and GCA factors to be implemented for the upcoming month, and quarterly earnings information.

Eleven smaller LDCs have petitioned the Commission to allow them to switch from quarterly to monthly GCA factors.[17] An evidentiary hearing is scheduled for late August 2001, after which the Commission will consider the evidence and issue an order. Additionally, one large LDC, Citizens, has a pending petition before the IURC for an ARP, which would, among other things, allow it to switch from quarterly to monthly GCA factors.[18]

Some customer advantages of switching from a quarterly to a monthly filing include: more accurate price signals, which may cause customers to adjust their consumption, a quicker return of over-collected gas costs, and quicker reductions in GCA factors in times of falling gas prices. For example, if the GCA factor rises in December due to an increase in gas prices, a customer still has the heating months of January, February, and March to adjust consumption to the extent that is possible. Under the

[15] Cause No. 37366 GCA 71, SIGECO; Approved 7/25/2001.
[16] Cause No. 41338 ARP, NIPSCO; Approved 12/1/1998.
[17] Cause No. 41884, et al ARP; Midwest Natural Gas, Peoples Gas & Power Co., Switzerland County Natural Gas, Indiana Utilities, Community Natural Gas, Fountaintown Gas Co., South Eastern Indiana Natural Gas, Indiana Natural Gas, Boonville Natural Gas, Chandler Natural Gas, Lawrenceburg Gas Co.
[18] Cause No. 41605 ARP, Citizens Gas & Coke Utility; Evidentiary hearing August 23, 2001.

traditional quarterly or semi-annual GCA process, by the time a customer receives the higher price signal the heating season is over. Some other LDC advantages include: reduction of the need to estimate future gas prices from five to eight months in the future down to just one month, smaller variances between estimated and actual costs due to the shorter time frame, quicker recovery of under-collected gas costs, and reduced regulatory and legal expenses due to the need for only one annual hearing versus the traditional four.

Some disadvantages could occur in times of volatile market prices as monthly rates ratchet up and down causing customer bills to swing up and down--even with constant or reduced consumption levels. Another potential disadvantage of monthly GCA rates with an annual hearing is a diminished Commission role in setting the proper GCA factor. Reducing the number of hearings down to one from two or four means that there could be less Commission oversight and may reduce Staff's ability to properly review GCA factors.

Natural Gas Storage

According to the EIA, withdrawals from storage provide additional gas supply during seasonal and short-term gas demand peaks, help keep pipelines and distributions in physical balance, and play an important role in commodity trading and management. From a policy perspective, it is important that regulatory bodies keep in mind the increasingly competitive nature of the natural gas market and its influence on storage. Gas storage issues distill down to ones of cost versus reliability. Utilities do not want to invest in inventories that have little chance of being used when market prices are lower than the average cost of gas in storage. Alternatively, customers do not want gas utilities to run short of gas during a critically cold period because they failed to invest in storage gas. As the gas market changes, it is important that regulators closely monitor the supply and use of gas storage by LDCs.

The National Gas Storage Market

A great economic attribute of natural gas is that it can be stored for use in various facilities which include: depleted reservoirs in oil and/or gas fields, aquifers, salt cavern storage and liquefied natural gas (LNG) storage tanks. These facilities are either located in market areas where customers actually use gas or near supply basins in production areas. In general, gas storage is filled during low utilization or off peak periods (April–October) and withdrawn during peak periods of high consumption (November–March). There are many costs associated with getting storage gas to customers when they need it most, irrespective of where the storage facility is located. These costs include the gas itself, transportation of the gas from the supply area to the market area, injection of the gas into the storage facility and withdrawal of the gas at the time of use. These aggregated costs determine the overall cost of storage gas, which influences the LDC's optimal operational use. How LDCs use storage gas is of prime concern to regulators, especially during periods of high prices and potential shortage.

LDCs use storage gas to balance forecasted needs against actual needs on a daily and/or monthly basis. Gas companies also use storage gas as a physical hedge to help ensure reliability during the winter months at times of peak load on the coldest days of winter. Finally, storage gas has also served as a financial hedge during the winter when average market gas prices are higher than average storage gas prices, which are normally purchased during the summer when prices abate. The historic dynamic of lower summer gas prices may be changing, however, and LDC's future use of storage gas as a financial hedge may be limited.

According to a February 6, 2001, EIA national report on natural gas storage, analysts were concerned that the nation might run out of working gas in storage prior to the close of the heating season in March 2001. The authors identified key areas as support for their concerns: working gas levels were the lowest for the start of a heating season since 1976, high natural gas prices during the first several months of the 2000 storage refill season caused some storage re-fillers to defer injections, and net withdrawals during November 2000 were the highest for the month of November in over a decade due to colder than normal weather. Fortunately, the nation did not run out of working gas in storage. As a result of the potential shortfall, however, gas storage has become an area of increased scrutiny of regulators and gas industry participants alike.

For the week ending June 22, 2001, the American Gas Association (AGA) storage forecast indicated that working gas storage would exceed last year's levels by 142 Bcf. As of July 20, 2001, the AGA reported that working gas storage for the week ending July 14, 2001 was 2,042 Bcf, 239 Bcf ahead of last year and 39 Bcf ahead of the five-year average.[19] If this trend continues, it is expected that there will be sufficient storage gas volumes for use this upcoming winter. The problem does not appear to be the availability of gas volumes to replenish storage but rather the price paid for the gas placed into storage and its impact on gas operations.

For natural gas to be economical as a financial hedge in competitive markets, the cost of storing gas generally must be less than the differential between the cost of gas in the withdrawal period and the refill period. It has been cautioned that increased demand for natural gas in the electricity generation sector during traditional off peak periods may increase competition for gas to refill storage and put upward pressure on natural gas prices. The historical schedule of refilling gas in the summer is expected to be crimped by Sunbelt air conditioners, whose demand for gas-fired electricity is rapidly increasing. This fundamental change in storage dynamics is of great concern to regulators, especially in states like Indiana where winter weather can be severe and dependence on gas in storage for space heating is critical.

This anticipated change in gas price dynamics did not manifest itself this summer, however. On July 30, 2001, the EIA reported that spot prices declined at the end of the week in a pattern typical for the summer. The EIA also noted that the August contract finished on the last day of trade to close at $3.17 per Dth due to a forecast for warmer weather during that week.[20]

Indiana Gas Storage Reserves

Based on responses from gas utilities in Indiana to the data request sent out by the IURC for Gas Forum 2001, most gas utilities believe that they will be able to refill their storage facilities prior to the upcoming winter. This suggests that gas storage will be available for reliability purposes, but its use as a

[19] See footnote 4.
[20] *Id.*

financial hedge will be determined by what the market price of gas is this coming winter. Most respondents suggest that the average cost of this summer's refill gas in storage will be between $4.00 and $5.00 per Dth. If the price of gas is low this winter, for example if spot market natural gas prices stay below the $4.00 per Dth level, then it would be economically sensible to use spot market rather than storage gas, which would reduce the usage of storage gas this winter. While having gas in storage would still be considered valuable from a reliability point of view, it would have limited value as a price hedge. The ultimate effect of this scenario is that businesses might consider not putting as much gas into storage the following year thereby potentially decreasing reliability. It is clear from LDC responses to the IURC's inquiry that last winter's experience of high gas usage and extremely high gas prices has gas utilities focused on the benefits and costs of gas storage management.

Merchant Power Plants

National

The growing use of gas in new generating plants to meet the increasing demand for electricity has sharply increased natural gas consumption since 1996. Because approximately 89% of planned capacity additions over the 1998-2007 period for U.S. electric utilities are gas fueled units, it is believed that future gas consumption for electricity production will increase significantly with profound impacts on the gas market.[21] At this time there are no comprehensive and definitive studies that analyze the impact of gas fired electric power plants on natural gas supply and transmission. The IURC, in conjunction with the State Utility Forecasting Group, is developing a computer model to aid in the study of the impacts of merchant plants on gas markets.

Natural gas turbine and combined-cycle plants have been the units of choice for new plant construction because of their relatively low costs and short construction lead times. Because of these factors and the ability to sell electricity at market based rates, U.S. gas-fired generating capacity is growing rapidly nationally. EIA reported that about 22 gigawatts of new gas-fired generating capacity was added in 2000 (an 18 percent increase from the 1999 level).[22] Various surveys by private organizations indicate that a much greater increment (30-50 gigawatts) of gas-fired generating capacity in 2001 is implied by the announced additions around the country. A similarly large increase for 2002 is possible given public announcements compiled to date.

Annual variations in natural gas demand in the electricity generation sector are attributable to weather variations (particularly during the summer months), the availability of alternative energy supplies (e.g. hydropower) and fuel prices.[23] The potential for net increases in gas demand associated with these new generating plants reinforces the conclusion that significant new natural gas supply, which may accrue from the very high rate of gas well completions currently estimated for North America, would probably

[21] Energy Information Administration, *Natural Gas 1998: Issues and Trends* (Washington: U.S. Department of Energy, 1999).

[22] A gigawatt is a unit of power equal to on billion watts.

[23] Energy Information Administration, Monthly Energy Review, DOE/EIA-0035 (2001/03) (Washington DC. March 2001).

be quickly absorbed. This would suggest that a relatively high floor for spot gas prices should be expected for at least another few years. [24]

The State of Indiana

During the year 2000, the state of Indiana saw a total of six gas fueled electric generating plants come on line. Details are depicted in the chart below.

Table 5: Merchant Plant Activity

Merchant Plant Name	Approved Capacity MW	Actual Capacity MW
Georgetown DTE	320	160
IPL	200	80
Worthington Generation	400	170
Duke Vermillion	640	640
Wheatland Generating Facility	500	500
Total Actual Capacity in 2000	2060	1550

At the Gas Forum 2001 conference, LDC representatives stated that gas usage by merchant plants is not expected to threaten the reliability of service to Indiana's gas consumers although one LDC representative thought that pressure problems could develop. Merchant power plants purchase gas under interruptible contracts, which is a cheaper but much lower priority service than the firm service used by LDCs. Pipelines are contractually obligated to serve the needs of their firm customers before those of interruptible customers.

Because of the current and expected increase in gas fueled power generation, representatives from the pipeline and power generation industries are organizing to form an Alliance of Energy Suppliers to both develop basic principles of practice and address the power generation needs. Gas suppliers understand that there may be a need to change their physical and rate infrastructure to service the needs of this growing segment of their business. Pipeline suppliers are currently working on alternative rate flow services to address the needs of their plants whose demand can change drastically within a 24-hour period.

[24] Capacity Additions by location and fuel type are listed in EIA's Electric Power Monthly. DOE/EIA-0226(2001/03) (Washington DC, March 2001).

Competition Initiatives in Natural Gas

National Overview

The gas industry has been competitive for years at the wholesale and large end-user level, as customers routinely purchase their gas supplies and other load-managing services in the marketplace. The AGA estimates that 90% of industrial gas consumed and 99% of electric utility gas volumes can choose their own natural gas supplier, and that 72% of commercial customers either can now, or will soon be able, to choose their own gas supplier. Larger customers are more likely to use customer choice because they have the resources and expertise to manage their gas supplies and the relatively small per unit savings is attractive over large volumes. In the industrial sector, the average gas use per customer using customer choice was over twenty times that of traditional sales customers.

In 1999, customer choice programs for residential customers were either new or just getting started. More than 26 million households, or roughly 50% of the nation's 57 million households with gas service, either had or will soon have the option of customer choice. For more detailed information, see Appendix C.

The subscription rates of residential gas customers are low, which is explained by several factors. In addition to the fact that savings may be limited due to the small per unit savings and low consumption levels, most residential customers are fully satisfied with the service provided by their gas utilities and lack the expertise to purchase gas. The recent increases in gas costs eroded the cost advantage of marketers, making their product offerings to residential customers much less attractive or more expensive than the services of gas companies.

Options for small customers are expected to increase. Many gas companies are lowering their minimum consumption levels so that more customers can use transportation services. Proposed and existing gas utility unbundling programs allow small customers to aggregate their consumption to meet minimum levels. Marketers and suppliers are also increasing efforts to serve smaller customers that do not have the expertise to purchase gas and make transportation arrangements without assistance.[25]

Status of Customer Choice in Indiana

Northern Indiana Public Service Company (NIPSCO) Customer Choice Program

The Commission approved NIPSCO's "Choice" program in its Order of October 8, 1997, in Cause No. 40342. The utility began phasing in its customer choice program in April 1998. The eligibility numbers increased from 50,000 residential and 1,500 business customers to include the entire customer base of 633,000 and 55,000, respectively. The Choice program's enrollment caps are 150,000 residential customers and 20,000 commercial customers. NIPSCO estimates that all of its customers will have access to unbundled service by January 1, 2005.

[25] American Gas Association, Policy Analysis Issues – Providing New Services To Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives 2000 Update, April 30, 2001.

NIPSCO participated in the Commission sponsored Gas Forum 2001. The Company reported that there had been a decrease in enrollment from last July of approximately 2,400 customers, which suggests an inverse relationship between price and participation in customer choice programs. Customers did not experience supplier defaults or service disruptions by marketers. Nationally, higher gas costs forced customers back to their native LDCs as marketers found it more difficult to compete with LDC rates for service, and many defaulted on their contractual obligations to provide service.

NIPSCO CHOICE PROGRAM

Table 6: Status Customer Choice as of March 2000

		Enrollment Caps		Participating		
Customer Type	Total 2001	Total	Percent of 2001 Total	Total	Percent of Eligible	Percent of 2001 Total
Residential	633,000	150,000	23.7	10,340	6.9	1.6
Business	55,000	20,000	36.4	3,718	18.6	6.8
Total	688,000	170,000	24.7	14,058	8.2	2.0

Citizen's Alternative Regulatory Plant

Citizens filed a petition docketed as Cause No. 41605 on November 23, 1999, requesting authority to implement an Alternative Regulatory Plan (ARP). The utility cites an increasingly competitive energy environment in which market forces have replaced traditional regulation as the primary reason for the proposed change. Implementation of its proposal will prospectively result in all customers being able to choose their gas supplier, with Citizens remaining one of the supplier choices. Key elements of Citizen's proposal include: 1) the phasing in of new unbundled services over a six-year period, 2) a monthly GCA to be reviewed annually, 3) affiliate guidelines that serve as ethical codes of conduct between the utility and other third-party suppliers, 4) Citizens acting as the supplier of last resort, 5) new service offerings for third-party suppliers, 6) no increase in its current rates, and 7) immediate service changes for large commercial and industrial users using over 50,000 Dth annually in the first year.

In the second year of the ARP Citizens can refine and supplement processes implemented in the first year. Remaining commercial and industrial customers will be allowed to participate in the third year. Residential customers will be allowed to participate in years four through six in phases. Multiple parties to the proceeding continue to negotiate a settlement. Once hearings are completed, the Commission will review the testimony and issue an order on this case.

Appendix A

COMBINED ANALYSIS OF GAS SALES DATA

Citizens Gas, Indiana Gas, NIPSCO, and SIGECO

	2000	1999	1998
Total Sales By Class (1,000 Dth)			
Residential	147,085	140,748	126,229
Commercial	60,522	53,958	52,061
Industrial	30,198	20,972	23,382
Other	25,419	33,109	22,586
Total	**263,224**	**248,787**	**224,259**
Total Transportation By Class (1,000 Dth)			
Residential	1,583	995	207
Commercial	12,034	14,122	10,188
Industrial	238,952	250,150	238,735
Other	4,932	5,838	2,938
Total	**257,501**	**271,105**	**252,069**
Total Throughput By Class (1,000 Dth)			
Residential	148,668	141,743	126,436
Commercial	72,557	66,929	62,250
Industrial	269,149	273,959	262,117
Other	30,352	37,261	25,525
Total	**520,726**	**519,892**	**476,328**
Percent Transportation to Throughput			
Residential	1.06%	0.70%	0.16%
Commercial	16.59%	21.10%	16.37%
Industrial	88.78%	91.31%	91.08%
Other	16.25%	15.67%	11.51%
Total	**49.45%**	**52.15%**	**52.92%**

ANALYSIS OF GAS SALES DATA FOR 1998, 1999, & 2000

CITIZENS GAS AND COKE UTILITY

	2000	1999	1998
Revenues By Customer Class			
Residential	$ 161,261,660	$ 142,642,436	$ 139,788,095
Commercial & Industrial	109,578,368	68,214,515	68,033,459
Other	25,905,386	1,313,594	(3,553,278)
Totals	$ 296,745,414	$ 212,170,545	$ 204,268,276
Sales By Customer Class in Dth			
Residential	25,385,884	23,301,309	21,471,821
Commercial & Industrial	23,289,509	14,805,666	13,531,926
Other	-	3,791,803	(506,300)
Totals	48,675,393	41,898,778	34,497,447
Revenues Per Dth			
Residential	$ 6.3524	$ 6.1216	$ 6.5103
Commercial & Industrial	$ 4.7051	$ 4.6073	$ 5.0276
Other	$ -	$ 0.3464	$ 7.0181
Average Rate	$ 6.0964	$ 5.0639	$ 5.9213

INDIANA GAS COMPANY, INC.

	2000	1999	1998
Revenues By Customer Class			
Residential	$ 341,536,963	$ 283,838,041	$ 274,164,168
Commercial & Industrial	142,546,514	114,232,782	125,575,381
Other	32,810,251	(3,943,023)	-
Totals	$ 516,893,728	$ 394,127,800	$ 399,739,549
Sales By Customer Class in Dth			
Residential	46,504,000	43,943,000	38,806,564
Commercial & Industrial	27,087,000	23,990,000	23,998,579
Other	-	(950,000)	-
Totals	73,591,000	66,983,000	62,805,143

Revenues Per Dth

	2000	1999	1998
Residential	$ 7.3442	$ 6.4592	$ 7.0649
Commercial & Industrial	$ 5.2625	$ 4.7617	$ 5.2326
Other	$ -	$ 4.1506	$ -
Average Rate	$ 7.0239	$ 5.8840	$ 6.3648

NORTHERN INDIANA PUBLIC SERVICE CO.

Revenues By Customer Class

	2000	1999	1998
Residential	$ 446,043,965	$ 361,206,716	$ 327,901,804
Commercial & Industrial	203,967,233	151,862,365	148,765,570
Other	92,964,935	78,322,348	45,172,940
Totals	$ 742,976,133	$ 591,391,429	$ 521,840,314

Sales By Customer Class in Dth

	2000	1999	1998
Residential	66,450,000	65,168,000	58,346,000
Commercial & Industrial	35,996,000	32,151,000	34,200,000
Other	24,786,000	34,468,000	22,795,000
Totals	127,232,000	131,787,000	115,341,000

Revenues Per Dth

	2000	1999	1998
Residential	$ 6.7125	$ 5.5427	$ 5.6200
Commercial & Industrial	$ 5.6664	$ 4.7234	$ 4.3499
Other	$ 3.7507	$ 2.2723	$ 1.9817
Average Rate	$ 5.8395	$ 4.4875	$ 4.5243

SOUTHERN INDIANA GAS & ELECTRIC CO.

Revenues By Customer Class

	2000	1999	1998
Residential	$ 57,560,161	$ 45,254,410	$ 47,956,612
Commercial & Industrial	24,162,167	18,397,732	19,028,906
Other	119,908	175,015	194,621
Totals	$ 81,842,236	$ 63,827,157	$ 67,180,139

Sales By Customer Class in Dth

Residential	8,745,355	8,566,559	7,924,707
Commercial & Industrial	4,347,473	4,130,263	3,914,622
Other	633,180	(426,930)	(223,594)
Totals	13,726,008	12,269,892	11,615,735

Revenues Per Dth

Residential	$ 6.5818	$ 5.2827	$ 6.0515
Commercial & Industrial	$ 5.5577	$ 4.4544	$ 4.8610
Other	$ 0.1894	$ (0.4099)	$ (0.8704)
Average Rate	$ 5.9626	$ 5.2019	$ 5.7835

Appendix B

RESIDENTIAL GAS BILLS AS OF JANUARY [illegible] RANKED HIGHEST TO LOWEST AT 200 THERMS IURC GAS DIVISION				
Rank	**Utility Name**	**150 Therms**	**200 Therms**	**250 Therms**
1	Northern Indiana Public Service Co.	$159.57	$210.91	$262.26
2	Westfield Gas Corporation	$144.81	$185.36	$225.90
3	Boonville Natural Gas Corporation	$137.70	$179.66	$221.63
4	Indiana Gas Company	$134.59	$175.40	$216.21
5	Ohio Valley Gas Corp. (ANR)	$129.41	$168.81	$208.22
6	Lawrenceburg Gas Co. (Rate G-2)	$128.48	$166.26	$204.04
7	Lawrenceburg Gas Co. (Rate G-1)	$128.10	$164.24	$200.38
8	South Eastern Indiana Gas Co.	$124.57	$162.41	$200.24
9	Indiana Utilities Corporation	$121.82	$158.65	$195.47
10	Citizens Gas & Coke Utility	$121.09	$157.44	$193.79
11	Ohio Valley Gas Corp. (TXG)	$120.89	$157.27	$193.65
12	Aurora Municipal Gas	$118.37	$156.95	$195.53
13	Peoples Gas & Power Co.	$119.11	$154.34	$189.58
14	Indiana Natural Gas Corporation	$117.13	$154.18	$191.22
15	Chandler Natural Gas Corporation	$116.90	$153.39	$189.88
17	Midwest Natural Gas Corp.	$116.56	$151.34	$186.12
18	Switzerland County Natural Gas	$115.19	$150.85	$186.51
16	Community Natural Gas - Rate 1	$116.44	$150.16	$183.87
19	Ohio Valley Gas, Inc.	$114.53	$148.97	$183.41
20	Community Natural Gas - Rate 2	$109.77	$141.26	$172.76
21	Fountaintown Gas Company, Inc.	$107.09	$139.60	$172.12
22	Southern Indiana Gas and Ele. Co.	$103.62	$134.82	$166.03
23	Northern Ind Fuel & Light Co., Inc.	$101.23	$130.65	$160.07
24	Kokomo Gas and Fuel Company	$89.07	$113.27	$137.47
25	Snow & Ogden Gas Company, Inc.	$75.20	$100.20	$125.20

For Purposes Of This Comparison: 100 Therms = 100 Ccf = 10 Dth = 10 Mcf

RESIDENTIAL GAS BILL COMPARISON (2001-1997)

BILLS CALCULATED BASED ON RATES IN EFFECT JANUARY FIRST OF EACH YEAR

RANKED HIGHEST TO LOWEST BASED ON 5 YEAR AVERAGE

IURC GAS DIVISION

		Consumption Level of 200 Therms					
Rank	Utility Name	5 Year Average	2001 Bills	2000 Bills	1999 Bills	1998 Bills	1997 Bills
1	Lawrenceburg Gas Co. (Rate G-1)	$143.73	$164.24	$124.22	$128.61	$145.68	$155.88
2	Westfield Gas Corp.	$141.04	$185.36	$123.92	$127.55	$140.09	$128.30
3	Lawrenceburg Gas Co. (Rate G-2)	$140.35	$166.26	$121.43	$120.68	$139.37	$154.03
4	Indiana Natural Gas Corp.	$134.14	$154.18	$122.08	$128.00	$133.82	$132.60
5	Northern Indiana Public Service Co.	$132.91	$210.91	$114.53	$110.55	$114.37	$114.17
6	Aurora Municipal Gas Utility	$132.80	$156.95	$117.06	$118.77	$130.39	$140.83
7	Indiana Utilities Corp.	$132.45	$158.65	$125.97	$121.13	$129.21	$127.28
8	Ohio Valley Gas Corp. (ANR)	$131.35	$168.81	$120.33	$125.49	$132.71	$109.43
9	Peoples Gas and Power Co.	$129.33	$154.34	$112.61	$122.48	$135.19	$122.03
10	Indiana Gas Co.	$127.71	$175.40	$114.46	$107.62	$118.66	$122.40
11	South Eastern Indiana Gas Co.	$127.38	$162.41	$120.71	$115.33	$119.99	$118.45
12	Boonville Natural Gas Corp.	$127.31	$179.66	$109.67	$105.55	$113.97	$127.71
13	Fountaintown Gas Co.	$126.70	$139.60	$118.76	$114.05	$146.14	$114.96
14	Midwest Gas Corp.	$125.78	$151.34	$112.11	$121.78	$134.33	$109.33
15	Community Gas Corp. (Rate 1)	$125.57	$141.26	$114.31	$111.28	$121.43	$139.55
16	Switzerland County Natural Gas Co.	$123.20	$150.85	$122.19	$106.42	$113.21	$123.34
17	Citizens Gas and Coke Utility	$121.02	$157.44	$108.58	$110.30	$117.58	$111.20
18	Ohio Valley Gas Corp. (TXG)	$119.29	$157.27	$98.75	$115.11	$113.81	$111.49
19	Community Gas Corp (Rate 2)	$117.53	$150.16	$105.56	$104.97	$112.05	$114.90
20	Northern Indiana Fuel and Light Co.	$117.07	$130.65	$105.41	$116.91	$117.79	$114.59
21	Ohio Valley Gas Inc.	$114.55	$148.97	$94.09	$108.71	$107.85	$113.13
22	Chandler Natural Gas Corp.	$114.27	$153.39	$108.35	$91.92	$106.52	$111.17
23	Southern Ind. Gas & Ele. Co.	$107.66	$134.82	$92.94	$101.12	$103.02	$106.42
24	Kokomo Gas and Fuel Co.	$106.74	$113.27	$96.00	$117.18	$110.07	$97.20
25	Snow and Ogden Gas Co.	$100.20	$100.20	$100.20	$100.20	$100.20	$100.20

For Purposes Of This Comparison: 100 Therms = 100 Ccf = 10 Dth = 10 Mcf

Appendix C

Residential Pilot Programs and Unbundling Initiatives

STATE	COMPANY	POTENTIAL # OF HOMES	POTENTIAL DEMAND (BCF)	IN-SERVICE DATE	PROPOSED OR COMPLETED GOVERNMENT ACTION
California	Pacific Gas & Electric	3,594,000	234.5	8/91	CPUC Rulings Issued, State Law Prohibits PUC From Further Res. Choice Until 2000
	San Diego Gas & Electric	70,000	3.7	8/91	
	Southern California Gas	473,000	27.6	In-Service	
Delaware	Conectiv Power Delivery	15,000	1.0	11/99	
Dist. of Columbia	Washington Gas	137,000	14.3	1/99	
Georgia	Statewide	1,733,000	98.7	11/98	State Law Passed
Illinois	Central Illinois Light Company	10,000	0.9	10/96	ICC Hearing
	Nicor Gas	1,777,000	212.7	1999	
	Peoples Gas Light & Coke	20,000	2.3	11/97	
Indiana	Citizens Gas & Coke	240,000	23.0	2004	URC Study Completed
	Northern Indiana Public Svce.	150,000	15.6	05/98	
Iowa	Statewide	799,000	71.4		IUB Rulemaking
	MidAmerican Energy	875	.1	11/95-10/96	
Kentucky	Columbia Gas of Kentucky	127,000	10.6	2/00	Proposed Legislation
Maryland	Baltimore Gas & Electric	544,000	39.7	11/97	PSC Recommendations Issued
	Columbia Gas	28,200	2.5	11/96	
	Washington Gas	200,000	18.3	11/96	
Massachusetts	Statewide	1,233,000	105.7	2000	Collaborative Workshops
Michigan	Battle Creek Gas	1,000	.1	04/97	PSC Hearings Being Held
	Consumers Energy	300,000	34.5	04/98	
	Michigan Consolidated Gas	1,108,000	138.8	04/97	
	SEMCO Energy	23,500	2.5	04/99	
Montana	Energy West	22,600	2.0	09/99	State Law, PSC Proceeding
	Montana Power	132,000	12.2	Winter 1999	
Nebraska	KN Energy	100,000	23.1	6/98	Localities Regulate Utilities
New Jersey	Statewide	2,246,000	209.4	12/99	State Law
New Mexico	Public Ser. of New Mexico	396,000	30.9	12/97	
New York	Statewide	4,151,000	370.7	In-Service	PSC Regulations Issued
Ohio	Cincinnati Gas & Electric	345,000	29.0	10/97	State Law Passed
	Columbia Gas of Ohio	1,236,000	105.8	04/97	
	East Ohio Gas	1,116,000	130.4	04/98	
Oklahoma	Oklahoma Natural Gas	672,000	48.9	TBD	Proposed Rulemaking
Pennsylvania	Statewide	2,487,600	241.5	7/2000	State Law
South Dakota	MidAmerican Energy	58,000	4.9	1995	
	North Western Public Service	34,000	2.9	1995	
Virginia	Columbia Gas of Virginia	26,000	1.9	12/97	State Law
	Washington Gas	344,000	30.5	7/98	
West Virginia	Statewide	362,000	31.4	1986	State Law
Wisconsin	Wisconsin Gas	23,532	2.6	11/96	PSC Report
Wyoming	KN Energy	10,000	1.0	06/96	PSC Study Completed
.	Questar Gas	19,000	1.9	1999	
TOTAL		26,364,307	2,339.5		

* In most cases, regulatory approval is needed for utilities to offer residential transportation services

Source: American Gas Association, Policy Analysis Issues – Providing New Services To Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives 2000 Update, April 30, 2001.